Electricity Market Module

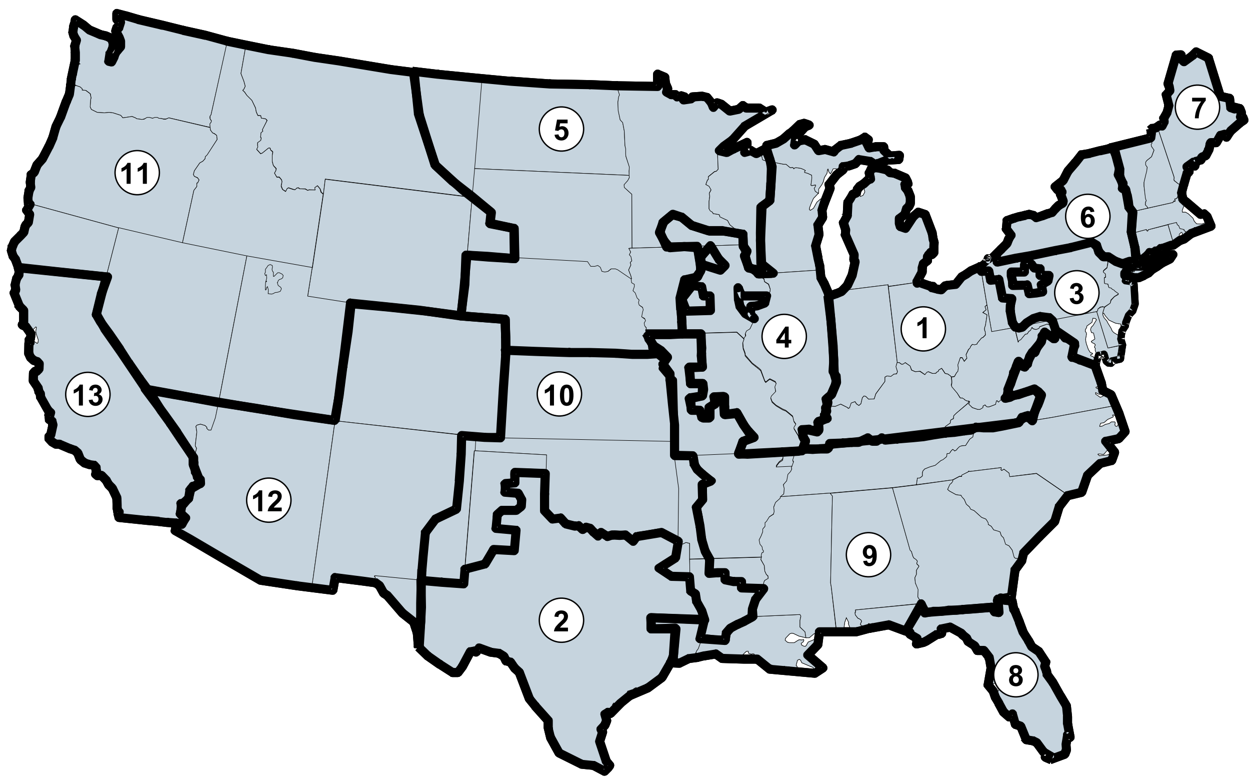
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *Electricity Market Module of the National Energy Modeling System 2003*, DOE/EIA-M068(2003) April 2003.

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM Regions

The supply regions used in EMM are based on the North American Electric Reliability Councils shown in Figure 4.

Figure 4. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement
2 Electric Reliability Council of Texas
3 Mid-Atlantic Area Council
4 Mid-America Interconnected Network
5 Mid-Continent Area Power Pool
6. New York
7 New England
8 Florida Reliability Coordinating Council
9 Southeastern Electric Reliability Council
10 Southwest Power Pool
11 Northwest Power Pool
12 Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada
13 California

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 39. Assumptions for the renewable technologies are discussed in a later chapter.

Table 39. Generating Capacity Types Represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Single Axis Flat Plate
Wind

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of No_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

New Generating Plant Characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 40). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies decline linearly through 2010.

The overnight costs shown in Table 40 are the cost estimates to build a plant in a typical region of the country *(Middletown, U.S.A*). Differences in plant costs due to regional distinctions are calculated by applying regional multipliers (Table 41) that represent variations in the cost of labor. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost used for the capacity choice decision.

Table 40. Cost and Performance Characteristics of New Electricity Generating Technologies

Technology	Online Years[1]	Size (mW)	Leadtimes (Years)	Overnight Costs[2] in 2002 ($2001/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost including Contingencies in 2002[4] (2001 $/kW)	Variable O&M[5] ($2001 mills/kWh)	Fixed O&M[5] ($2001/kW)	Heatrate in 2002 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal Newl	2006	600	4	1,079	1.07	1.00	1,154	3.07	24.52	9,000	8,600
Integrated Coal-Gasification Combined Cycle	2006	550	4	1,277	1.07	1.00	1,367	2.04	33.72	8,000	7,200
Conventional Gas/Oil Combined Cycle	2005	250	3	510	1.05	1.00	536	2.04	12.26	7,500	7,000
Adv Gas/Oil Combined Cycle	2005	400	3	563	1.08	1.00	608	2.04	10.22	7,000	6,350
Conv Combustion Turbine[6]	2004	160	2	389	1.05	1.00	409	4.09	10.22	10,939	10,450
Adv Combustion Turbine	2004	230	2	439	1.05	1.00	460	3.07	8.17	9,394	8,550
Fuel Cells	2005	10	3	1,850	1.05	1.10	2,137	20.43	7.15	7,500	6,750
Advanced Nuclear	2007	1000	5	1,750	1.10	1.10	2,117	0.43	58.48	10,400	10,400
Distributed Generation - Base	2005	2	3	766	1.05	1.00	804	6.13	13.79	9,400	8,900
Distributed Generation - Peak	2004	1	2	919	1.05	1.00	965	6.13	13.79	10,400	9,880
Biomass	2006	100	4	1,569	1.07	1.05	1,763	2.96	45.94	8,911	8,911
MSW - Landfill Gas	2005	30	3	1,365	1.07	1.00	1,460	0.01	98.42	13,648	13,648
Geothermal [7,8]	2006	50	4	1,681	1.05	1.00	1,766	0.00	71.75	32,320	31,797
Wind	2005	50	3	938	1.07	1.00	1,003	0.00	26.10	10,280	10,280
Solar Thermal[8]	2005	100	3	2,204	1.07	1.10	2,594	0.00	48.91	10,280	10,280
Solar Photovoltaic[8]	2004	5	2	3,389	1.05	1.10	3,915	0.00	10.06	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2002.

[2]Costs reflect market status and penetration as of 2002.

[3]The technological optimism factor is applied to the first four units of a new, unproven design. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2002.

[5]O&M = Operation and maintenance.

[6]Combustion turbine units can be built by the model prior to 2004 if necessary to meet a given region's reserve margin.

[7]Because geothermal cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[8]Capital costs for geothermal and solar technologies are net of (reduced by) the ten percent investment tax credit.

Source: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the 'Notes and Sources' section at the end of the chapter.

Table 41. Regional Multipliers for Construction of Fossil-Fueled, Nuclear, and Renewable[1] Generating Technologies

EMM Region	NE, NY	MAAC	STV	MAPP, ECAR, MAIN	SPP
	1.043	0.996	0.96	1.004	0.997
EMM Region	**RA**	**NWP**	**FL**	**CNV**	**ERCOT**
	1.003	1.026	0.961	1.058	0.986

[1]Regional multipliers are not applied to geothermal technologies because costs are site specific.

Source: Argonne National Laboratory, *Cost and Performance Database for Electric Power Generating Technologies*..

Technological Optimism and Learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors. For each generating technology available for new capacity in a region, the overnight cost used by the model is calculated using the base cost, technological optimism and contingency factors for the technology from Table 40, the regional factors from Table 41, and the learning parameters from Table 42.

Table 42. Learning Parameters for New Generating Technologies

Technology	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2020
Conventional Pulverized Coal	-	-	0.01	-	-	0.05
Integrated Coal-Gasification Combined Cycle	-	0.05	0.01	-	5	0.10
Gas/Oil Steam Turbine	-	-	0.01	-	-	0.05
Conv Gas/Oil Combined Cycle	-	-	0.01	-	-	0.05
Adv Gas/Oil Combined Cycle	-	0.05	0.01	-	5	0.10
Conv Combustion Turbine	-	-	0.01	-	-	0.05
Adv Combustion Turbine	-	0.05	0.01	-	5	0.10
Fuel Cells	0.1	0.05	0.01	3	5	0.20
Adv Nuclear	-	0.05	0.01	-	5	0.10
Distributed Generation - Base	-	0.05	0.01	-	5	0.10
Distributed Generation - Peak	-	0.05	0.01	-	5	0.10
Biomass	0.1	0.05	0.01	3	5	0.20
MSW - Landfill Gas	-	-	0	-	-	0.05
Geothermal	-	0.05	0.01	-	5	0.10
Wind	-	-	0.01	-	-	0.01
Solar Thermal	0.1	0.05	0.01	3	5	0.20
Photovoltaic	0.1	0.05	0.01	3	5	0.20

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function has the nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology.

The progress ratio (*pr*) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (f) is an exogenous parameter input for each technology Table 42. Consequently, the progress ratio and *f* are related by:

$$pr = 2^{-b} = (1 - f)$$

The parameter "b" is calculated by (b =-(ln(1-*f*)/ln(2)). The parameter "a" can be found from initial conditions. That is,

$$a = OC(C0)/C0^{-b}$$

where C0 is the cumulative initial capacity. Thus, once the rates of learning (f) and the cumulative capacity (C0) are known for each interval, the corresponding parameters (a and b) of the nonlinear function are known. Three learning steps were developed, to reflect different stages of learning as a new design is introduced to the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. All technologies receive a minimal amount of learning, even if new capacity additions are not projected. This could represent cost reductions due to future international development or increased research and development.

International Learning. In *AEO2003*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the U.S. market, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the domestic learning effects calculation.

AEO2003 includes 784 megawatts of advanced coal gasification combined-cycle capacity, 4,199 megawatts of advanced combined-cycle natural gas capacity, and 11 megawatts of biomass capacity to be built outside the United States from 2001 through 2003.

Distributed Generation

Distributed generation is modeled in the end-use sectors as well as in the EMM, which is described in the appropriate chapters. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). Use Table 40 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Representation of Electricity Demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Council regions and subregions) using historical hourly load data. However, unlike traditional load duration curves where the demands for an entire period would be ordered from highest to lowest, losing their chronological order, the load duration curves in the EMM are segmented into the 9 time periods shown in Table 43. The summer and winter peak periods are represented in the model by 2 vertical slices each (a peak slice and an off-peak slice) while the remaining 7 periods are represented by 1 vertical slice each, resulting in a total of 11 vertical slices. The time periods shown were chosen to accommodate intermittent generating technologies (i.e., solar and wind facilities) and demand-side management programs.

Table 43. Load Segments in the Electricity Market Module

Season	Months	Period	Hours
Summer	June-September	Daytime	0700-1800
		Morning/Evening	0500-0700 and 1800-2400
		Night	0000-0500
Winter	December-March	Daytime	0800-1600
		Morning/Evening	0500-0800 and 1600-2400
		Night	0000-0500
Off-peak	April-May	Daytime	0700-1700
	October-November	Morning/Evening	0500-0700 and 1700-2400
		Night	0000-0500

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are also assumed for each regulated EMM region. A 13 percent reserve margin is assumed for MAPP and STV, 9 percent for FL, 15 percent for NWP, and 14 percent for CNV. In the other regions where competition has replaced regulation in all or a majority of the region, the EMM determines the reserve margin by equating the marginal cost of capacity and the cost of unserved energy.

Fossil Fuel-Fired and Nuclear Steam Plant Retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operating of existing plants. If the expected revenues from these plants are not sufficient to cover the annual going forward costs, the plant is assumed to retire if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant specific based on historical data. The average capital additions for existing plants are $11 per kilowatt (kW) for oil and gas steam plants, $6/kW for combined-cycle plants, and combustion turbines, $16/kW for coal plants and $18/kW for nuclear plants. These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $5/KW capital charge for fossil plants, and $50/kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

Biomass Co-firing

Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $100 to $200 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional supply.

New Nuclear Plant Orders

A new nuclear technology competes with other fossil-fired and renewable technologies as new generating capacity is needed to meet increasing demand, or replace retiring capacity, throughout the forecast period. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide. The capital cost assumptions in the reference case are meant to represent the expense of building a new single unit nuclear plant of approximately 1,000 megawatts at a new “Greenfield” site. Since no new nuclear plants have been built in the US in many years, there is a great deal of uncertainty about the true costs of a new unit. The EIA accounts for this uncertainty by requiring that the capital cost estimates be symmetric in the sense that there is an equal probability that they could turn out to be either “too high” or “too low.” For that reason, the estimate used for AEO2003 is an average of the ones reviewed from various sources (See ‘Notes and Sources’ at the end of the Chapter for a full list of sources reviewed).

It is also important to note that there is a great deal of uncertainty about how the nuclear technology will evolve over the next 20 years. Currently, two conventional light water reactors along with the smaller, passively safe, Westinghouse AP600 power plant have had their designs certified by the NRC. A larger version of the Westinghouse design is also under review with the NRC. Additionally, the process to certify a number of more revolutionary reactor designs is just beginning. Thus, it is quite possible that within the next 20 years there will be wide range of designs that have been licensed by the NRC and could be built. Rather than attempting to “pick the winners” the cost estimates used here are more general, and do not deal with any one design.

Nuclear Power Uprates and Restarts

AEO2003 assumes that the Browns Ferry 1 nuclear unit will return to operation in 2007. The unit has been shut down since 1985 for safety issues but has retained an operating license. The Tennessee Valley Authority, owner and operator of the Browns Ferry plant, recently decided to make the investment required to return the plant to service, which is expected to take 5 years.

The *AEO2003* nuclear power forecast also assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modifications, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and AEO forecasts accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. The NRC approved 22 applications for power uprates in 2001, and another 22 were approved or pending in 2002. *AEO2003* assumes that all of those uprates will be implemented, as well as others expected by the NRC over the next 10 years, for a capacity increase of 4.2 gigawatts between 2002 and 2025. Table 43a provides a summary of projected uprate capacity additions by region. In cases where the NRC did not specifically identify the unit expected to uprate, EIA assumed the units with the lowest operating costs would be the next likely candidates for power increases.

Table 43a. Nuclear Upratres by EMM Region
(gigawatts)

Region	
1	0.15
2	0.26
3	0.54
4	0.57
5	0.27
6	0.01
7	0.02
8	0.04
9	2.17
10	0.01
11	0.01
12	0.07
13	0.10
Total	4.23

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Interregional Electricity Trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the NERC and WSCC Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's *Electricity Supply and Demand Database 2000*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2010 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2010, they are assumed to be phased out by 2020. In addition, in certain regions where data show an established commitment to build plants to serve another region, new plants are permitted to be built to serve the other region's needs. This option is available to compete with other resource options.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are allowed to exchange power.

International Electricity Trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Existing and planned transactions are obtained from the North American Electric Reliability Council's *Electricity Supply and Demand Database 2000*. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report *Northern Lights: The Economic and Practical Potential of Imported Power from Canada*, (DOE/PE-0079).

International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections as reported in the Canadian National Energy Board report *Energy Supply and Demand to 2025.*

Electricity Pricing

The reference case assumes a transition to full competitive pricing in New York, New England, Mid-Atlantic Area Council, and Texas. California is assumed to return to fully regulated pricing in 2002, after beginning to transition to completition in 1998. In addition electricity prices in the East Central Area Reliability Council, the Mid-American Interconnected Network (Illinois, plus parts of Missouri, Michigan and Wisconsin), the Southwest Power Pool, and the Rocky Mountain Power Area/ Arizona are a weighted average of both competitive and regulated prices. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. The price for the region will be a weighted average of the competitive price and the regulated price, with the weight based on the percent of the region that has taken action to deregulate. The reference case assumes that State-mandated price freezes or reductions during a specified transition period will occur based on the terms of the legislation. In general, the transition period is assumed to occur over a ten-year period from the effective date of restructuring, with a gradual shift to marginal cost pricing. In regions where none of the states in the region or where states representing less than half of regional electricity sales have introduced competition, electricity prices are assumed to remain regulated. The cost-of-service calculation is used to determine electricity prices in regulated regions.

The price of electricity to the consumer is comprised of the price of generation, transmission and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the *AEO*; that is, the price of transmission and distribution is based on the average cost for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The marginal cost includes fuel, operating and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. Therefore, the price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. The price of electricity in the four regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution. In the four partially competitive regions the price is a combination of cost-of-service pricing and marginal pricing weighted by the share of sales.

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2002*. The key trends are discussed below:

- Reduced General and Administrative Expenses (G&A) - Over the 1990 through 1999 period, utilities have reduced their employment at fossil steam plants at a rate of 4 percent per year. This trend has been incorporated by reducing total G&A expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

- Reduced Fossil Plant Operations Expenditures (O&M) - Again, over the 1990 through 1999 period, utility fossil plant operation and maintenance costs (all operating costs other than fuel) fell at a rate of about 3 percent annually. As with G&A, this trend has been incorporated by reducing fossil O&M expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

Fuel Price Expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 20-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas, and oil are derived using adaptive expectations, in which future prices are extrapolated from recent historical trends.[92] For each oil product, future prices are estimated by applying a constant markup to an external forecast of world oil prices. The markups are calculated by taking the differences between the regional product prices and the world oil price for the previous forecast year. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on expected demand changes throughout the forecast horizon, resulting in updated mining utilization and different supply curves.

For natural gas, expected wellhead prices are based on a nonlinear function that relates the expected price to the expected cumulative domestic gas production. Delivered prices are developed by applying a constant markup, which represents the difference between the delivered and wellhead prices from the prior forecast year.

The approach for natural gas was developed to have the following properties:

1. The natural gas wellhead price should be upward sloping as a function of cumulative gas production.

2. The rate of change in wellhead prices should increase as fewer economical reserves remain to be discovered and produced.

The approach assumes that at some point in the future a given target price, PF, results when cumulative gas production reaches a given level, QF. The target values for PF and QF were assumed to be $7.00 per thousand cubic feet (1995 dollars) and 2000 trillion cubic feet (tcf), respectively. Gas hydrates are included in the resource base at a level of 60 tcf, and geopressurized aquifers are included at 500 tcf. There is also the flexibility to assume a different path in the short term and longer term by choosing an inflection price at which new competitors would enter the market.

The expected wellhead gas price equation is of the following form:

$$P_k = A * Q_k^{exp} + B$$

where P is the wellhead price for year k, Q_k is the cumulative production from 1991 to year k, and A and B are determined each year such that the price equation will intersect the future target point (PF, QF). The exponent, exp, is assumed to be 0.70 as long as P_k is below an assumed inflection price of $3.50. Above this price, the exponent is assumed to be 1.30. The cumulative production calculation assumes that future growth in production will be equal to most recent 3 year average growth rate.

The point (P_k , Q_k) therefore represents the expected wellhead price given the expected cumulative production. A series of supply steps are then developed around this point to represent changes in the expected price that could occur if the cumulative production differs from the expected value. The expected quantity is varied by assuming different levels of consumption, which could result from capacity additions, fuel switching, or other operating decisions. After determining the relative change from the expected production for each step, the corresponding price is derived by applying an elasticity to the expected wellhead price.

Legislation and Regulations

Clean Air Act Amendments of 1990 (CAAA90)

It is assumed that electricity producers comply with the CAAA90, which mandate a limit of 8.95 million tons by 2010. Utilities are assumed to comply with the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. It is assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000 (Table 44). Dry bottom wall-fired, and tangential fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet their Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. All of these NO_x limits are incorporated in EMM.

Table 44. NO_x Emissions Standards
(Pounds per million Btu)

Boiler Type	# Boilers	Phase I Limit	Phase II Limit
Group 1 Boilers			
Dry Bottom Wall-Fired	284	0.50	0.45
Tangential	296	0.45	0.38
Group 2 Boilers			
Cell Burners	35	NA	0.68
Cyclones	88	NA	0.94
Wet Bottom Wall-Fired	38	NA	0.86
Vertically Fired	29	NA	0.80
Fluidized Bed	5	NA	0.29

NA = Not Applicable.

Source: Environmental Protection Agency, Nitrogen Oxide Emission Reduction Program.

In addition, the EPA has issued rules to limit the emissions of NOx, specifically calling for capping emissions during the summer season in 22 Eastern and Midwestern states. After an initial challenge, these rules have been upheld, and emissions limits have been finalized for 19 states and the District of Columbia (Table 45). Within EMM, electric generators in these 19 states must comply with the limit either by reducing their own emissions or purchasing allowances from others who have more than they need.

Table 45. Summer Season NO_x Emissions Budgets for 2004 and Beyond
(Thousand tons per season)

State	Emissions Cap
Alabama	29.02
Connecticut	2.65
Delaware	5.25
District of Columbia	0.21
Illinois	32.37
Indiana	47.73
Kentucky	36.50
Maryland	14.66
Massachusetts	15.15
Michigan	32.23
New Jersey	10.25
New York	31.04
North Carolina	31.82
Ohio	48.99
Pennsylvania	47.47
Rhode Island	1.00
South Carolina	16.77
Tennessee	25.81
Virginia	17.19
West Virginia	26.86

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 42 (March 2, 2002) pages 11222-11231.

The costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2)and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NO_x) are given below for 300, 500, and 700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NO_x. The costs per megawatt of capacity tend to decline with plant size and this is shown in table 46.

Table 46. Coal Plant Retrofit Costs
(2001 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	**267**	**93**
500	**204**	**82**
700	**168**	**74**

Source: CUECOST3.xls model (as updated 2/9/2000) developed for the Environmental Protection Agency by Raytheon Engineers and Constructors, Inc. EPA Contract number 68-D7-0001.

Note: The model was run for each individual plant assuming a 1.3 retrofit factor.

Planned FGD (SO2 scrubber) Additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, nearly 23,000 megawatts of capacity are assumed to add these controls (Table 47). The greatest number of retrofits is expected to occur in Region 9 because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 47. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Megawatts)
1	1,715
2	1,160
3	1,906
4	173
5	0
6	105
7	837
8	524
9	12,638
10	0
11	1,340
12	2,421
13	0
Total	22,819

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Energy Policy Act of 1992 (EPACT)

The provisions of the EPACT include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs).

The Public Utility Holding Company Act of 1935 (PUHCA)

Prior to the passage of EPACT, PUHCA required that utility holding companies register with the Securities and Exchange Commission (SEC) and restricted their business activities and corporate structures.[93] Entities that wished to develop facilities in several States were regulated under PUHCA. To avoid the stringent SEC regulation, nonutilities had to limit their development to a single State or limit their ownership share of projects to less than 10 percent. EPACT changed this by creating a class of generators that, under certain conditions, are exempt from PUHCA restrictions. These EWGs can be affiliated with an existing utility (affiliated power producers) or independently owned (independent power producers). In general, subject to State commission approval, these facilities are free to sell their generation to any electric utility, but they cannot sell to a retail consumer. These EWGs are represented in NEMS.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and a Open Access Same-time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.

Electricity and Technology Cases

High Electricity Demand Case

The *high electricity demand case* assumes that electricity demand grows at 2.5 percent annually between 2001 and 2025. In the reference case, electricity demand is projected to grow 1.8 percent annually between 2001 and 2025. No attempt was made to determine the changes needed in the end-use sectors to result in the stronger demand growth.

The *high electricity demand case* is a partially integrated run. The end-use demand modules are not operated, but all of the electricity end-use demands from the reference case are multiplied by the same factor to achieve the higher growth rate. Using the higher electricity demand and all other reference case demand projections as inputs, the EMM, Petroleum Marketing, Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact.

Low and High Fossil Cases

The *low fossil case* assumes that the costs of advanced fossil generating technologies (integrated coal-gasification combined-cycle, advanced natural gas combined-cycle and turbines) will remain at current costs during the projection period, that is, no learning reductions are applied to the cost. Operating efficiencies for advanced technologies are assumed to be constant at 2002 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 48).

In the *high fossil case*, efficiencies of advanced fossil generating technologies are higher than the reference case, based on the Department of Energy, Office of Fossil Energy's Vision 21 program goals, while efficiencies of conventional technologies are the same as used in the reference case. The costs of advanced coal are also assumed to be lower than in the reference case.

In the high fossil case, the efficiency improvements may be achieved through a new design, for example, inlcuding a fuel cell in addition to a combined cycle. It is assumed that research and development will bring the costs of these new designs down to the levels of the current technology.

The *low and high fossil* runs are partially-integrated runs, i.e., the reference case values for the Macroeconomic Activity, Petroleum Market, International Energy, and end-use demand modules are used and are not affected by changes in generating capacity mix. Conversely, the Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the EMM in the *low and high fossil cases*.

Advanced Nuclear Cost Case

An advanced nuclear cost case was used to analyze the sensitivity of the projections to lower costs for new nuclear plants. The cost assumptions are consistent with the goals endorsed by the Department of Energy's Office of Nuclear Energy and indicated as requirements for cost-competitiveness by the Offices Near-Term Deployment Working Group. In this case, the overnight capital cost, including contingencies, of a new advanced nuclear unit is assumed to be $1500/kilowatt initially, and to fall to $1200/kilowatt by 2020, (costs in year 2000 dollars)[94] (Table 49). The cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 48. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2002 (Reference)	Total Overnight Cost[1]			Heatrate in 2002 (Reference)	Heat Rate		
		Reference	High Fossil	Low Fossil		Reference	High Fossil	Low Fossil
	(2001$/kW)	(2001$/kW)	(2001$/kW)	(2001$/kW)	Btu/kWhr	Btu/kWhr	Btu/kWhr	Btu/kWhr
Pulverized Coal	1155				9000			
2010		1128	1134	1128		8689	8689	8689
2015		1101	1022	1095		8600	8600	8600
2020		1086	1109	1079		8600	8600	8600
2025		1080	1097	1072		8600	8600	8600
Adv. Coal	1367				8000			
2010		1320	1023	1367		7378	6799	7911
2015		1290	998	1367		7200	6104	7911
2020		1260	973	1367		7200	5687	7911
2025		1231	949	1367		7200	5687	7911
Conv Combined Cycle	536				7500			
2010		527	527	527		7056	7056	7056
2015		521	521	521		7000	7000	7000
2020		515	515	515		7000	7000	7000
2025		509	509	509		7000	7000	7000
Adv. Gas Technology	608				7000			
2010		549	549	608		6422	5717	6928
2015		513	513	608		6350	4960	6928
2020		503	503	608		6350	4960	6928
2025		494	494	608		6350	4960	6928
Conv. Combustion Turbine	409				10939			
2010		402	402	402		10450	10450	10450
2015		397	397	397		10450	10450	10450
2020		393	393	393		10450	10450	10450
2025		388	388	388		10450	10450	10450
Adv. Combustion Turbine	461				9394			
2010		391	391	461		8550	6669	9394
2015		355	355	461		8550	6669	9394
2020		351	351	461		8550	6669	9394
2025		348	348	461		8550	6669	9394

1. Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects initiated in the given year.

Source: AEO2003 National Energy Modeling System runs: AEO2003.D110502C, HFOSS03.D110602A, LFOSS03.D110602A.

Table 49. Cost Characteristics for Advanced Nuclear Technology: Two Cases

Advanced Nuclear	Overnight Cost in 2002 (Reference) (2001$/kW)	Total Overnight Cost[1]	
		Reference Case (2001$/kW)	Adv Nuclear Case (2001$/kW)
	2118		
2010		2044	1535
2015		1998	1380
2020		1952	1228
2025		1906	1228

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects initiated in the given year.

Source: AEO2003 National Energy Modeling System runs: AEO2003.D110502C, ADVNUC03.D110602A.

Notes and Sources

[93] Energy Information Administration, Integrating Module of the National Energy Modeling System: Model Documentation, DOE/EIA-M057(2000), (Washington, DC, December 1999).

[93] A registered utility holding company is defined as any company that owns or controls 10% of the voting securities of a public utility company. PUHCA defines a public utility company as any company that owns or operates generation, transmission, or distribution facilities for the sale of electricity to the public.

[94] Year 2000 dollars are shown here to be consistent with program office goals.

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